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Interconnection and generation from a North Sea power hub – A linear electricity model

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ABSTRACT

We research effects on the electricity market of countries surrounding the North Sea after a proposed offshore wind park in the Dogger Bank area of the North Sea has been constructed. Interconnection and generation distribution are analysed separately. The supply price of electricity for each country is calculated by a linear regression analysis to simulate the supply price for higher or lower supply. The model uses the coupling of one supply with one receiver country. Linear modelling of the electricity market combines the results for each objective to find a final state for the market. Using the historic market and weather data for 2016, the results from interconnection show an average generated value of 0.275 [M€/hour] and 82.1 [GW] of average energy flow through the hub. The results of this interconnection between the countries bring between −26% and +11% change on average electricity prices. For hub generation added in, we found an average generated value of 0.573 [M€/hour] and an average price drop of 5% for each country for an average wind power generation of 6.3 [GW] at the hub. The results show that interconnecting the similarly sized electricity markets i.e. Great Britain and Germany & the Netherlands and Denmark, where one has a higher renewable share, would bring the most price stabilization between the two as well as generate the most financial return.

1. Introduction

Transmission system operators of 3 countries (the Netherlands, Denmark and Germany) have recently signed an agreement, to construct an offshore wind park in the form of an energy island in the North Sea [1]. Subsequently, natural gas transmission system operators such as Gasunie and the Port of Rotterdam have joined the consortium [2]. This energy island is based on the hub and spoke principle (Fig. 1). Whereas a point-to-point system between *n* countries requires *n(n-1)/2* connections, a hub and spoke central needs only *n* connections and this can affect the whole network [3]. [4] has emphasized the importance of increasing transmission interconnectivity by a factor of approximately 4 within the EU, as well as the critical role of prosumers and storage allowing a 100% renewable energy system. This project aims at better interconnection amongst the electricity markets of six North Sea countries (NSC): United Kingdom (GB), Norway (NO), Denmark (DK), Germany (DE), the Netherlands (NL) and Belgium (BE). Recent studies have convincingly demonstrated that it is the integration of renewable sources which delivers the largest benefits to the grid [5]. [6] has confirmed this by recommending the need for the integration and development of communication technologies between transmission and distribution networks. Following that, [7] have confirmed the benefit of wind power quantitatively on the German electricity market having compared the effect of offshore and onshore wind parks on the spot price. This research concluded no difference in price reduction effect between offshore and onshore wind power. On the same topic, [8] has looked into the market effect of large-scale wind power on profit generation in forward and day head electricity markets. [9] has looked more into the risks and effect of poorly predictable wind power on the day ahead and spot market prices. With increasing uncertainty in the prediction of generation and demand in a market with a large share of wind power, [10] compared day-ahead, intraday, and regulating power markets and indicated more relevance to the markets closer to real-time. Indeed, an integrated grid making use of multiple offshore generations is envisioned [11,12]. These could utilise platform facilities above abandoned oil and gas reservoirs [13]. A recent

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Nomenclature

Symbols

a	slope of price quantity line
b	intercept of price quantity line
k	energy exchanged between supplier and receiver country
L_g	generation limit of a country
L_R	receiver limit of a country
L_S	excess generation capacity of a supplier
P	price
ΔP	initial price difference between trading countries
Q	energy
V	value generated at hub
W	amount of sold wind energy

sub/superscripts

0	initial price in a country
‘	subsequent state when selling to the second country starts
‘’	subsequent state when selling to the third country starts
d	demand
i	supplier
j	receiver
s	supply

abbreviations

NSC	North Sea Countries (GB, NO, DK, DE, NL, BE)
NC	Not Connected
CGD	Country Generation Distribution
HGD	Hub Generation Distribution
GB	Great Britain
DE	Germany
DK	Denmark
NL	The Netherlands
BE	Belgium
NO	Norway

study has gone further than radial project design to evaluate other integrated connection topologies and quantify potential benefits [14]. [15] gives an overview of cumulative total installed capacity, as well as the annually installed wind turbine capacity. The results of this research show that in 2020 Germany appeared by far as the pioneer in cumulative installed wind turbine capacity of 31 [GW] which is larger than the next top 3 EU members combined.

The higher wind speed and stability in far off-shore locations are more advantageous for large scale power generation, compared to land-based or coastal systems. This has been the subject of a recent study optimising layouts based on wind and wave factors [16]. The higher costs for construction/maintenance far from shore, however, make offshore wind farms less favourable compared to onshore ones [7]. Wind turbines generate AC so that transfer losses per kilometre are 40% higher than for DC. Installing a high voltage direct current (HVDC) converter platform adds to cost [17]. With an energy island nearby, however, the converters can be placed on the island [17]. A port on the island also provides a logistical advantage for installation and maintenance.

There are two objectives for the proposed energy island in the North Sea. It can be used as a centre to build cheaper largescale offshore wind-farms on and around it which subsequently distribute electricity to these countries – so-called hub generation and distribution (HGD). It is of course also used for better interconnection of countries around the North Sea i.e. country generation and distribution (CGD) and we start by considering this option i.e. only interconnection. The associated research question for the country generation distribution scenario (CGD) is: What is the maximum value generated by optimum energy flow between North Sea countries (NSC) via the hub? For the hub generation distribution (HGD) scenario the question is: what is the best distribution for wind energy generated at the hub that leads to the maximum value at each hour? Associated questions produce the amounts of energy flow between NSCs for each scenario and the associated cable size for each objective. A previous study [18] examined a combined distribution and interconnection scenario but only with average electricity prices. Some approaches have used bottom-up estimates for modelling combined heat and power scheduling of energy hubs [19]. However, the preferred approach is a phenomenological one that develops a pricing strategy in response to dynamic load development [20] and this is what is used in this study.

In Section 2 a model for electricity price simulation is introduced. Section 3 presents optimisation strategies for each scenario followed by a model in Section 4 to find optimum energy flows between all 6-NSCs. The optimization aims for the highest value generated and uses the historic data as initial market status (price and load). The new market status after optimum interconnection (CGD) is used as input for optimum wind generation (HGD) which gives the final market status.

2. Price model

With the import of power from neighbouring countries, [21] has shown that the electricity price will drop from initial status (market clearing price) to final status (competitive benchmark price). An Italian case study by [22], has used piece-wise linear functions to model the

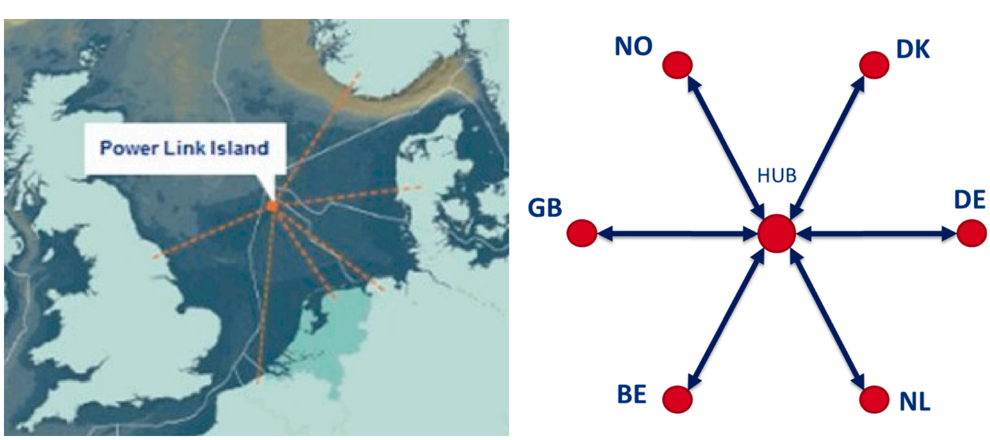

Fig. 1. Power Link Island [1] with schematization of the hub and spoke concept.

market clearing process aiming for optimal hourly zonal electricity prices. Following this research, a linear price function has been used to model the effect of power import on the electricity market.

We start from the assumption that each country individually is able to supply its own demand. i.e. the supply quantity is equal to demand quantity resolved on an hourly basis ($Q_s = Q_d$). This implicitly includes already existing interconnections that do not go through the proposed hub. After connection with the hub, the demand per country will not change, but import or export via the hub (Q_s) will affect the supply price (P_s). Since we only consider supply price and supply quantity in our calculations the subscript "*s*" referring to the supply side are eliminated from here on for simplicity.

The price-supply correlation determines what happens to electricity price in a country as different quantities are supplied. Providing we are not near the capacity of the country; this can be modelled linearly based on the data averaged over a year (see Fig. 2 based on 2016) [23,24].

$$P_s(Q) = aQ_s + b \tag{1a}$$

The coefficient *a* is the slope of the supply price against quantity and measures the sensitivity. This is the main sensitivity factor we use in our analysis below. The constant term *b* is the effective marginal cost of electricity as it refers to the cost when there is no supply. As noted above we have used the values from the year 2016. We justify this by the observation that the spread of the annual average values *a* and *b*, between years is much smaller than the spread within a year as characterised by the root mean square (rms) deviation of the price. Explicitly this is quantitatively stated as follows: Fig. 2 shows a widespread in prices for each country. We drop the subscript for supply *s* and replace it with a subscript denoting year *k* which is the straight-line fit:

$$P_k(Q) = a_k Q + b_k \tag{1b}$$

There is a rms (root mean square) deviation in the price within a year given by $\overline{\delta P_k}$. Correspondingly between different years *k* there is a rms deviation in the price given by $\overline{\Delta P}$. This rms variation in the price line between different years $\overline{\Delta P}$ is a lot less than $\overline{\delta P_k}$the rms variation of price within a year i.e. $\overline{\delta P_k} \gg \overline{\Delta P}$. This is simply a quantification of the observation that seasonal variations *within* a year are always considerably more than a variation of the annual average *between* years. For this reason, a consideration of just the spread over a single year is sufficient to model the system.

We have to avoid being near the generational capacity limit of the country where severe non-linearity is to be expected. Our method for doing this is discussed in 3.1 below after we have extracted what these limits are. The limits on the quantity that can be supplied for each country are obtained along with the *a* and *b* factors of Eq. (1) above, from the hourly historical market data (demand and electricity price) for all 6-NSCs [23,24]. It is noted that our optimization takes place for each hour separately and is based on historic data either for 2016 or forecasted for 2016. As discussed above, we have assumed that – before optimisation - supply equals demand at any hour. We fit the coefficients from Eq. (1) by regression analysis to hourly resolved data for all 6 NSC (Table 1 shows coefficients *a* and *b* for all 6 NSCs). Having these supply price lines, we can estimate what happens to the supply price of electricity in each country if the supply deviates from the demand (see next section). As can be seen from Fig. 2, not all the historic data are on the characteristic line associated with each country. To avoid this becoming a source of error, only the linear fits have been used to simulate the price when supply varies.

A final point in Fig. 2 is the finite potential of supply as given by the extent of quantity along the *x*-axis i.e. the quantity range that one country can supply to another. In any kind of trade, there are two limits:

1. *Supplier limit (L_S):* The supplier, in general, cannot sell any more than its generation capacity. Since country *i* is supplying power, it can support the excess generation capacity left from supporting its own demand ($L_S = L_g - Q_i$). Generation limit (L_g) in this formula is the highest recorded demand in our historic data. Although countries, in general, can support more than their highest recorded demand (due to security of supply) [24], because of the exponential increase in supply price close to its limit, we have used these values so that our constant slope approach is more realistic.
2. *Receiver limit (L_R):* The receiver cannot receiver any more than its demand. Since country *j* is receiving the energy we have $L_R = Q_j$. Although the receiver country (which is also the more expensive one) might have some storage capacity to store cheap electricity for later use, in this report it has not been considered. Thus, the most country *j* can benefit from cheap electricity provided by country *i*, is theoretically from its total demand.

Considering these two basic limits, the energy flow between the traders is restricted by the minimum of these (L_S and L_R). Consequently,

Table 1
Price quantity coefficients with power generation limits based on the highest recorded demand flows between countries.

Country	abbr.	code	$10^3 a$(€/ (MWh)^2)	*b*(€/MWh)	L_g(GWh)
Great Britain	GB	1	1.6	−1.8	77.9
Norway	NO	2	0.7	15.2	24.5
Denmark	DK	3	5.4	6.8	6.6
Germany	DE	4	0.5	−2.0	79.2
Netherlands	NL	5	3.4	−10.1	18.6
Belgium	BE	6	4.7	2.0	13.7

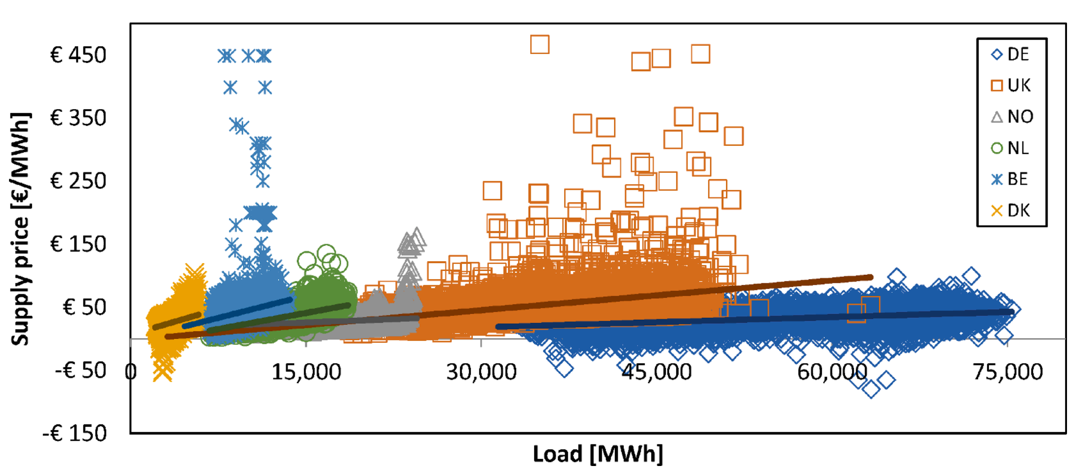

Fig. 2. Supply price vs. demand for all 6 NSCs [23,24]

calculated values for energy exchanged (see below) cannot exceed the limits given in Table 1.

As can be seen in Fig. 2, some countries like Germany have lower slopes (a) since their electricity markets are well prepared to meet higher demands and their electricity price is relatively stable throughout the whole spectrum – see Table 1. Germany has a large scale generation of renewables (such as wind) with zero marginal cost. Thus, the cost of bringing in extra energy to a secondary country is low – this is reflected by the low (and negative) value of b as well as the large generation limit. These factors allow the supply price to be lower.

Countries like Germany and Denmark have some negative values in their electricity price range. This is an indication of substantial amounts of renewables in their grid. For these sources, the marginal costs of generation are almost zero. A major factor in determining electricity cost is the regional balancing of the grid [25]. If there is too much renewable energy, the costs associated with balancing the grid would increase rapidly. This in turn causes the spot price to drop below zero simply because the grid balance measures in place cannot deal with overloaded inflexible supply. Hence for the grid to stabilize at those instances distribution service operators (DSO) pay their clients to use electricity to avoid overloads and damage to infrastructure. The reason why they do not stop generating at those times of oversupply is either inflexibility in baseload (i.e. shutdown and start-up of generating power plants) and/or government subsidies for renewables.

By contrast, countries like the United Kingdom and Belgium show larger variations in their electricity price. This is due to insufficient national gas-fired power plants which can fire up quickly and avoid price spikes. The second cause of large price variations is poor interconnectivity inside a country.

Last but not least, it is important to keep in mind that the simplified price function used in this study is merely used for comparison of relative electricity price response of different countries to find out the profitable ones.

Now that the dynamic electricity price for each country has been described, we proceed to our analysis of the effects of interconnectivity which is demonstrated by initially analysing a 2-country model which we then generalise to all 6 countries with which we are concerned.

3. Methodology

3.1. Country generation and distribution (CGD)

Consider two countries i and j which trade electricity. Each country has its own supply price line. At any point in time, one country has a lower electricity price and can supply the other. However, as energy is transferred from the cheaper supply country i (source) to the more expensive customer country j (sink), the price in the supplier country i (source) goes up and the price in the customer country j (sink) goes down. In an ideal model, and providing supply and receiving limits are not exceeded, then the 2 prices will eventually meet, although non-linearities normally occur before this point to which we will not go on this study – see the previous section. Now we can proceed to calculate that optimum energy flow in the ideal case by setting the new prices at each side of the energy exchange to be the same.

Each country has its own specific slope a to characterize their price changes as the quantities demanded and supplied change for the source i and sink j respectively. Representing the initial and final (within the context of the CGD situation) status by unprimed and primed variables respectively, then after an exchange of energy k, defined by

$$Q_i^{'} - Q_i = Q_j - Q_j^{'} = k \tag{2}$$

where i is a supplier and j a receiver. Recalling from Eq. (1)

$$\frac{P_i^{'} - P_i}{Q_i^{'} - Q_i} = a_i; \frac{P_j^{'} - P_j}{Q_j^{'} - Q_j} = a_j \tag{3}$$

and solving for p_i' and p_j', then inserting Eq. (2) into Eq. (3) gives

$$P_i^{'} = P + a_i k; P_j^{'} = P_j - a_j k \tag{4}$$

the energy transfer process stops when $P_i' = P_j'$ so that the amount of energy exchanged is given by

$$k = \frac{P_j - P_i}{a_i + a_j} \tag{5}$$

which shows the amount of energy exchanged in terms of the initial price in the source and sink countries. Recalling the definitions in Eq. (1), k can also be expressed in terms of the initial quantity of supplies in each country before exchange:

$$k = \frac{(a_j Q_j - a_i Q_i)}{a_i + a_j} + \frac{(b_j - b_i)}{a_i + a_j} \tag{6}$$

Note that this value is based on an *average* change in price with respect to the quantity of supply. However, as Fig. 2 shows, there is a significant spread around the straight-line approximation (In effect we have taken a sequence of time values and used their average to give a demand line). The initial status used for estimating the transfer potential is by definition, almost never on the average line. In other words, specifying a and b rarely gives a market status and also unduly constrains the optimisation process. In our analysis, we are mainly concerned with the average rate (i.e. the factors) at which the change occurs - the first term on the right-hand side of Eq. (6). For this reason, in the analysis that follows, we ignore the second term on the right-hand side. The b terms which determine the second smaller term in Eq. (6) only have physical meaning at $Q = 0$ – the lower extreme for supply which is beyond the limit of the linearity of the model (as in the case of generation limit discussed in the previous section.) Thus, instead of using the exact line that we found through regression, we can ignore the b coefficient and simply look at the average price change with quantity of supply as measured by the slope a i.e. the first term on the right-hand side of Eq. (6).

A parameter for the value from energy exchange is derived from averaging the sales income for the source and the generating saving for the sink [17,25]. The net benefits for each side of the energy exchange are given in equations for the supplier and receiver respectively. It is important to realize that this net benefit is in reality the gross social benefit and the marginal generation costs (such as maintenance etcetera) are not taken into account.

$$V = \frac{1}{2}\left(k\left(P_i^{'} - P_i\right) + k\left(P_j^{'} - P_j\right)\right) \tag{7}$$

In the ideal case prices after the power trades meet ($P_i^{'} = P_j^{'}$). The total value generated is only a function of the initial price difference between traders (ΔP) and the a coefficients. Thus

$$V = \frac{k}{2}\left(P_j - P_i\right) = \frac{k}{2}\Delta P \tag{8}$$

3.2. Hub generation and distribution (HGD)

In the foregoing country generation distribution (CGD) scenario, the hub only acted as infrastructure connecting the countries which generated electricity. We now look at the effect of adding generational capacity in the hub itself. The market status of a country at any time is represented by a point. If there is no hub generation, the local price moves up and down the characteristic lines with slope a as soon as power is injected (less need for self-supply) or taken out of its grid (export to another country). In the case of hub generation, only a price decrease occurs because the marginal cost of renewable energy generation is very small compared to traditional sources – the only marginal cost is maintenance. We have not looked at the hub as a separate actor in terms of having its own price line.

The highest value from hub generation is not achieved by simply selling to the country with the highest electricity price at any moment as we did for a country generation. In CGD we linked the countries to maximise value. However, in reality, the value comes not just from price difference but is also limited by the transfer limits from the supplier and receiver side. In the current model, the dynamic price lines respond to the quantity of *self-supplied* electricity (which decreases as soon as external power enters their national grid and vice versa). It does not correctly model externally supplied electrical energy. The whole price modelling system is only valid for CGD while the same price modelling system (the same line and slope) holds in all cases. We aim to sell generated wind energy at the highest local instantaneous prices.

We address this problem by using the concept of merit order which looks only at sink price levels. This is the order in which power plants get used as suppliers for a given demand. This starts with the power plants with the lowest marginal costs. Our linear model follows the same principle as all the slopes (a) in Table 1 are positive. We begin by selling wind power to the country (1) with the highest price P_1^0. Due to dynamic pricing, as energy is received from the hub the electricity price of that country drops to $P_1^{'}$ as it is receiving energy from the hub. This drop $P_1^0 - P_1^{'}$continues until the next highest price country (2) is reached i.e. the point is reached where $P_1^{'} = P_2^0$ (see Fig. 3).

At this point, wind power is sold to both countries in a way that the price drop is the same amongst both (as shown in Fig. 3):

$$P_1^{'} - P_1^{''} = P_2^0 - P_2^{'} \tag{9}$$

Note that the quantities of energy transferred are different due to the different price response a_i for country i. This process continues until both prices meet the next highest priced country (3). At this point, wind power is sold to all 3 countries 1, 2 and 3. These 3 countries again would receive wind power in a way that all would have the same price decrease. The same strategy continues until all wind energy generated at the hub is sold. Therefore, all countries receiving wind power from the hub for an hour would have the same electricity price after generation distribution is finished for that hour. For an amount of wind energy (W) sold to a country j, the value generated is the same as in Eq. (7) above. i.e. the area under the supply line from the initial price P_i to the final price P_f.

$$V = W*(\frac{P_i - P_f}{2}) \tag{10}$$

The total value generated at each hour is the sum of all such values for all the receiving ("sink") countries. We now turn to the model for interconnecting countries.

4. Interconnection model

In the previous section, we described the two scenarios we wish to study. We also described in the introduction that the hub and spoke interconnection reduces the interconnection from 15 to 6 points. We now define how we define which of the links are "active" at any hour - i.e. which links generate the most value. There are 6 potential sources/sinks ("nodes") to be pairwise connected corresponding to a total of $^6C_2 = 15$ possible combinations. All these links go through the hub. At any hour, any of these links could be chosen to exchange electricity between the two countries on either side. We have simplified our model in a way that if two countries are interconnected, they cannot exchange with a third country. In other words, for any supplier (source) of the electricity, there is only one receiver (sink) i.e. one source one sink.

The question is: What is the best independent combination of these links that leads to the most value generated from interconnection? To find that optimum combination we define several scenarios whereby we include only the links that are independent of each other. In other words, if a link is chosen in a scenario, the other links chosen should not overlap with them. This leads to 3 links out of all 15 possible since there are only 6 countries in our model. Considering this simplification, from combination theory we reduce the number of scenarios for each hour to as low as 15. In Fig. 4, a sample scenario is given to visualize the links and the direction of power. The direction of the energy is not considered in the scenarios (Table 2) since theoretically, only one direction is profitable – thus defining the energy flow direction.

Table 2 shows the country codes and Table 3 shows all the scenarios in terms of country codes. For instance, in scenario 1 from Table 3, Link 1 shows Great Britain and Norway are connected, Link 2 shows Denmark and Germany are interconnected, and Link 3 shows the Netherlands and Belgium as interconnected. The direction of the energy flow depends on the hourly electricity price. The results are optimised by choosing the scenario that generates the most benefit and calculates the corresponding energy transfer and value. Knowing the mechanism of optimization for each objective of the hub, we can proceed to the results section.

5. Results and discussion

Based on the model presented for country generation distribution (CGD) and hub generation distribution (HGD) of the island, the results split into 2 sections for each objective. Recall the two assumptions: there is only pair coupling between one source and one sink, and these are mutually exclusive with no overlap. One last assumption made in this report is the sequence of optimization (which is possible due to linear modelling). We assume that first the interconnection of the NSC are optimized CGD (to generate most value), then the hub generation distribution (HGD) of the island is optimized (for the same goal). We then determine the incremental value of hub generation. Although this order can play a role in value generated, the reverse order (generation distribution first and interconnection second), would essentially lose most of CGD's impact due to levelized prices between all the countries receiving wind power. This levelized prices would basically contribute to the existence of less potential for CGD. Hence to see the effect of both,

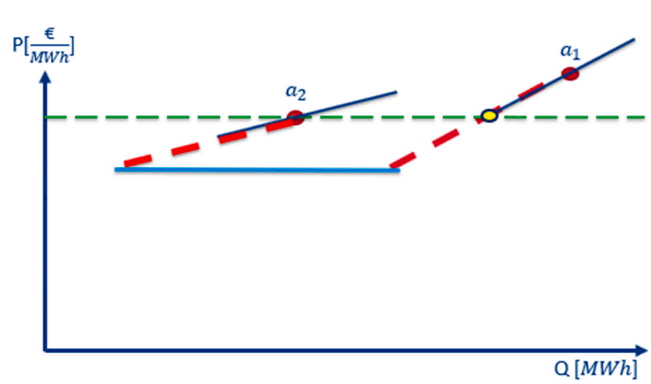

Fig. 3. Selling strategy for hub generation distribution (HGD).

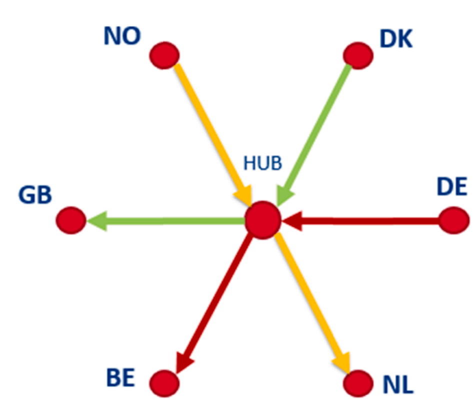

Fig. 4. Sample scenario for interconnection.

Table 2
Country codes for scenario definition.

Country	GB	NO	DK	DE	NL	BE
Code	1	2	3	4	5	6

we chose interconnection to take place first (stabilizing the prices between links) and then generation distribution (stabilizing the prices between the ones receiving wind power).

5.1. Interconnection (CGD)

Recalling from the modelling section for interconnection, we have defined 15 scenarios for each hour that chooses 3 independent links. The optimization function finds the scenario in which the highest total value (from the 3-chosen link) is generated and returns the energy flows and total value *for that hour*. Table 4 shows the occurrence of the scenarios (counts for the number of [hours/year] they occurred). In Table 5 on the other hand, we show link occurrence based on the percentage of hours it has been included in the best scenario (thus taking part in energy exchange).

According to Table 4, scenario number 9 is the most profitable one with 31.7% occurrence over a year. Thus for 32% of the time electricity flow from Germany to Great Britain, from Norway to Belgium and from Denmark to the Netherlands. This is in accordance with the fact that the average electricity price in GB and BE is generally higher than that of DE and NO respectively (Fig. 2). Considering that in general Germany and Norway have high shares of renewable electricity (including hydropower) compared with the United Kingdom and Belgium respectively [26,27], and the marginal costs of renewable power are insignificant, the two links in the most occurring scenario suggests the potential of interconnection between countries with more renewable share to the lower ones. In terms of most profitable links, however, from Table 5, it appears that the link between Great Britain and Germany occurs the most often in the interconnection. This is also following the fact that 2 of the most profitable scenarios (number 8 and 9) both include these links. Note that although there can be overlap in terms of links between 2 different scenarios, they cannot overlap for any more than one link. (If 2 links are determined, the third one follows.) Therefore, the two scenarios are unique. The same logic applies to the link between Denmark and the Netherlands. Both links are included in scenario number 2 and 8. These both occur for 21% of the time in both most profitable scenarios respectively (Table 4). In total, an average energy flow of 82.1 [GW] and an average value of 0.275 [M€/hour] are found from optimizing interconnection.

5.2. Generation distribution (HGD)

For any amount of generation, the selling strategy is as explained above. 1000 SeaTitan wind turbines, each having a capacity of 10 [MW], have been considered for a hypothetical offshore wind farm at the hub. From weather data for 2016 and the geographic location of (54.5;2.0), we estimate a wind speed at 125 m above sea level in order to calculate the actual hourly energy production. Hence, the maximum hub generation in our optimization is at most considered to be 10 [GW]. For comparison, a recent public study regarding a hydrogen electrolyser facility in this energy island [28] has reported scalability of 3.5 up to 20 [GW] Hydrogen production capacity which at times of no possible HGD the excess electricity generation can be stored in the form of power to hydrogen.

Fig. 5 shows the effect of the hub on the average electricity supply for each country. For reference, we show the electricity price for the countries when they are not connected ("NC") for comparison with the CGD and HGD scenarios identified above. From Fig. 5, Germany and Great Britain are receiving the most wind power. This is due to the optimization of interconnection first. After interconnection, the receiving wind power is incorporated in the hub generation distribution (HGD) scenario. The average price (Fig. 6) in Denmark is slightly higher than in Norway. In addition, Denmark's price/supply response is more sensitive (Table 1) with a slope of $a_{DK} = 0.0054$ compared to that of Norway $a_{NO} = 0.0007$. Corresponding wholesale prices (Fig. 6) (i.e. excluding the sustainable energy mark-up) of electricity in Great Britain and Germany are still the highest. This gives them priority over other countries. Following our value maximisation distribution strategy shown schematically in Fig. 3, it gets a bigger share from hub generation distribution (HGD) for this reason. Fig. 7 shows the fraction of hub generated wind energy imported per country. For Norway, this is 26% compared to 3% for Denmark. Our selling strategy effectively caps the highest prices within all NSCs. This does not take away from the fact – as we shall see below – that Norway is of course a net exporter of energy. We need to bear in mind that hub generation and distribution is small compared to country generation and distribution.

Based on optimum generation distribution (HGD) of a 10 [GW] wind park at the hub, an average generated value of 0.573 [M€/hour] is found. Comparing this with CGD we can see that for about several times larger energy flow through the hub (under HGD), about another 50% of the value is generated. This is because the incremental generation at the hub has no extra OPEX. It is selling power to the receiver country and its supply price decreases while selling wind power, due to the dynamic pricing of the receiver.

Table 5
Link occurrence percentage over a year of optimized interconnection.

Country	GB	NO	DK	DE	NL	BE
GB	–	32%	4%	60%	2%	3%
NO	–	–	8%	4%	23%	33%
DK	–	–	–	7%	54%	27%
DE	–	–	–	–	7%	22%
NL	–	–	–	–	–	15%
BE	–	–	–	–	–	–

Table 3
All 15-scenarios including 3 independent links.

Scenario	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Link 1	1–2	1–2	1–2	1–3	1–3	1–3	1–4	1–4	1–4	1–5	1–5	1–5	1–6	1–6	1–6
Link 2	3–4	3–5	3–6	2–4	2–5	2–6	2 3	2–5	2–6	2–3	2–4	2–6	2–3	2–4	2–5
Link 3	5–6	4–6	4–5	5–6	4–6	4–5	5–6	3–6	3–5	4–6	3–6	3–4	4–5	3–5	3–4

Table 4
Scenario occurrence hour and percentage over a year of optimized interconnection.

Scenario	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Count	513	1803	499	116	114	84	650	1808	2778	36	72	65	17	152	78
%	5.8	20.5	5.7	1.3	1.3	1.0	7.4	20.6	31.7	0.4	0.8	0.7	0.2	1.7	0.9

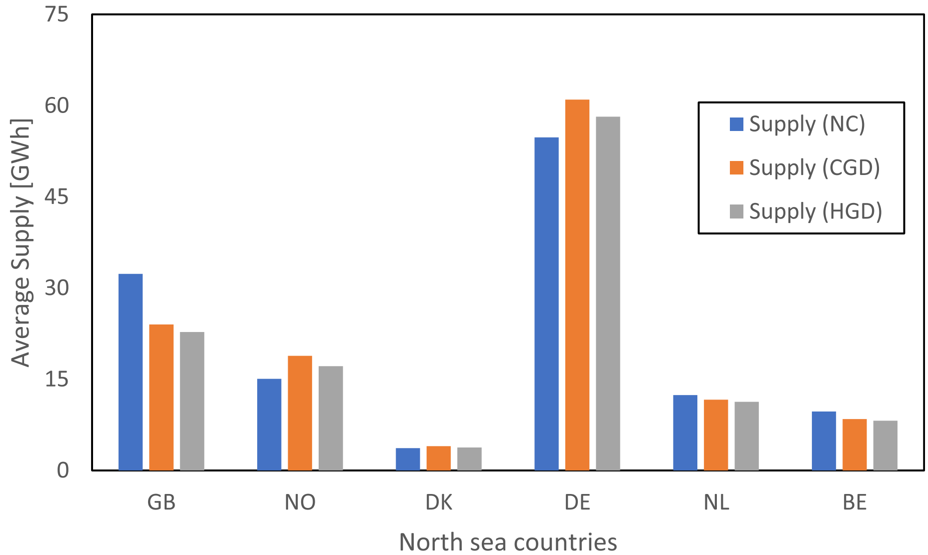

Fig. 5. Hub's effect on average electricity self-supplied per country for not connected (NC), country generation distribution (CGD) and hub generation distribution (HGD).

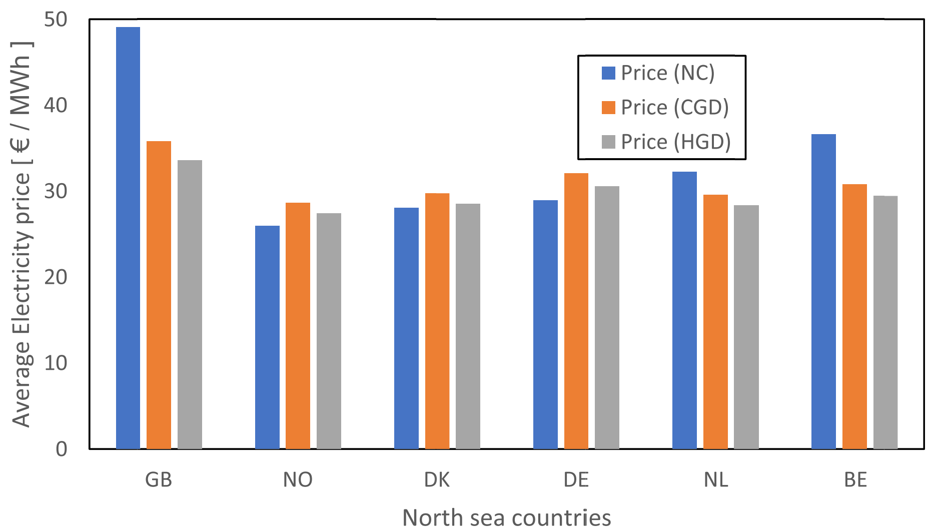

Fig. 6. Hub's effect on average electricity price per country not connected (NC), country generation distribution (CGD) and hub generation distribution (HGD).

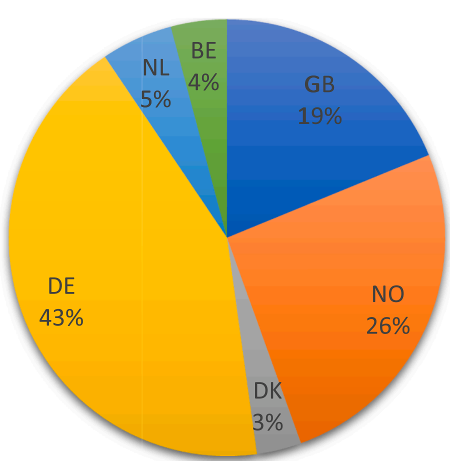

Fig. 7. Wind power imported per country.

5.3. Discussion

Tables 6 and 7 show supply and price changes for each objective compared to its input market status. A negative value indicates a supply/price drop and vice versa. In our chosen optimization sequence, the input market status for CGD is the real market data. Outputs of CGD are then used as the input market status for HGD.

- Average price (and thus average supply) values are negative for Great Britain for whom the hub is thus most beneficial. This again is due to price instabilities and a high average price in recorded historical data.

Table 6
Average electricity supply percentage change per objective.

Country	GB	NO	DK	DE	NL	BE
Average supply change (CGD)	−26%	25%	9%	11%	−6%	−13%
Average supply change (HGD)	5%	9%	5%	5%	3%	3%

Table 7
Average electricity price percentage change per objective.

County	GB	NO	DK	DE	NL	BE
average price change (CGD)	−27%	10%	6%	11%	−8%	−16%
average price change (HGD)	−6%	−4%	−4%	−5%	−4%	−4%

- The Netherlands is also one of the countries benefiting from the hub, although not as much as Great Britain and Belgium from CGD (-8% or the Netherlands versus −16% and −27% for Belgium and Great Britain respectively).
- For German customers, however, CGD is not beneficial. (i.e. As we have already established it would be mostly supplying cheap electricity to Great Britain). For HGD on the other hand, Germany receives wind power more often as its price was increased from interconnection. This is also supported by the fact that Germany has a relatively more stable electricity market that responds less severe to imported electricity. The same logic applies to Norway and Denmark.
- For HGB, we see an average price drop of approximately −5% across different countries. This price reduction effect is in line with findings of [7] which compared the onshore and offshore wind power effect on the market price of electricity.

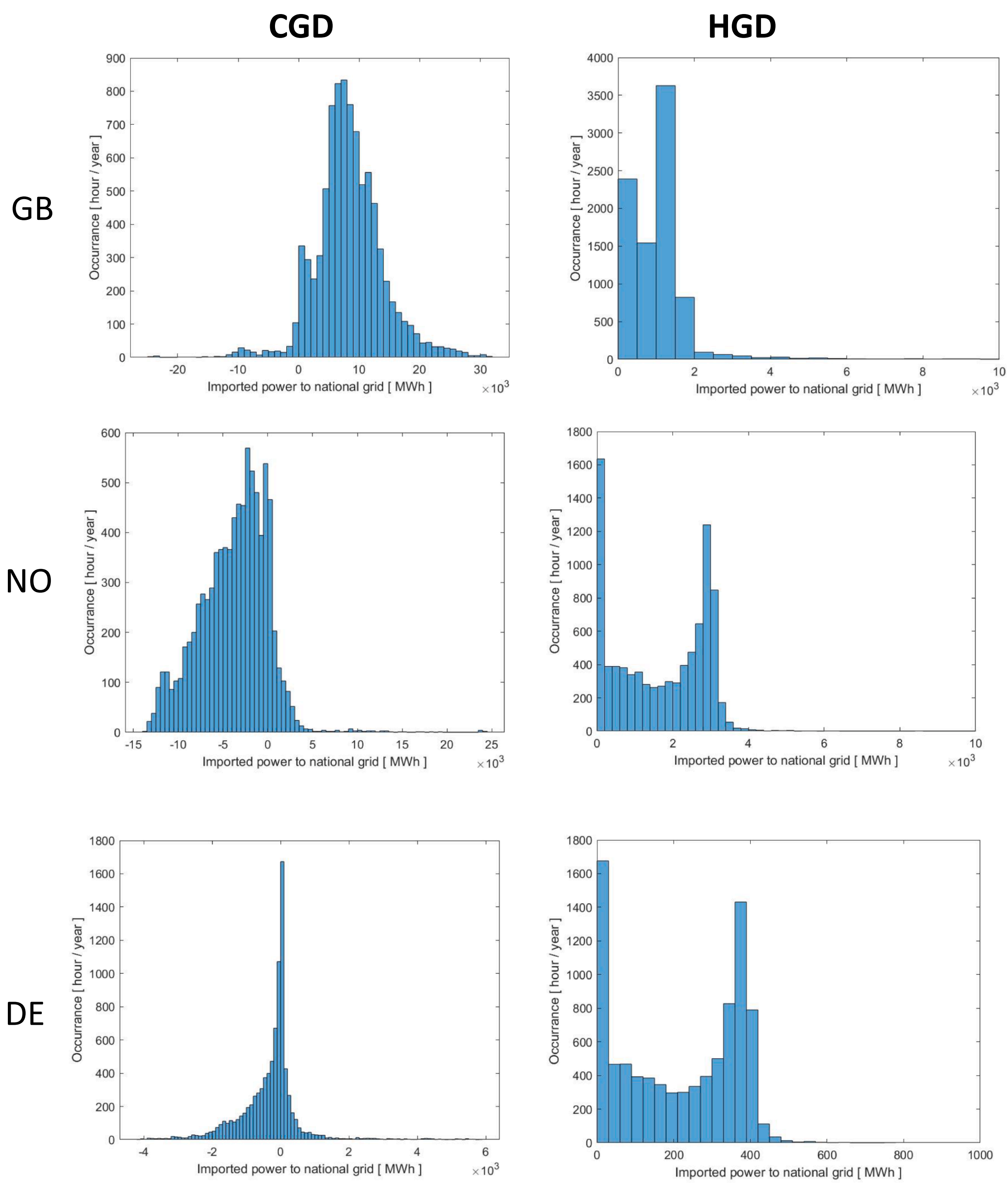

Fig. 8. Power flowing between each country and the hub for both per objective.

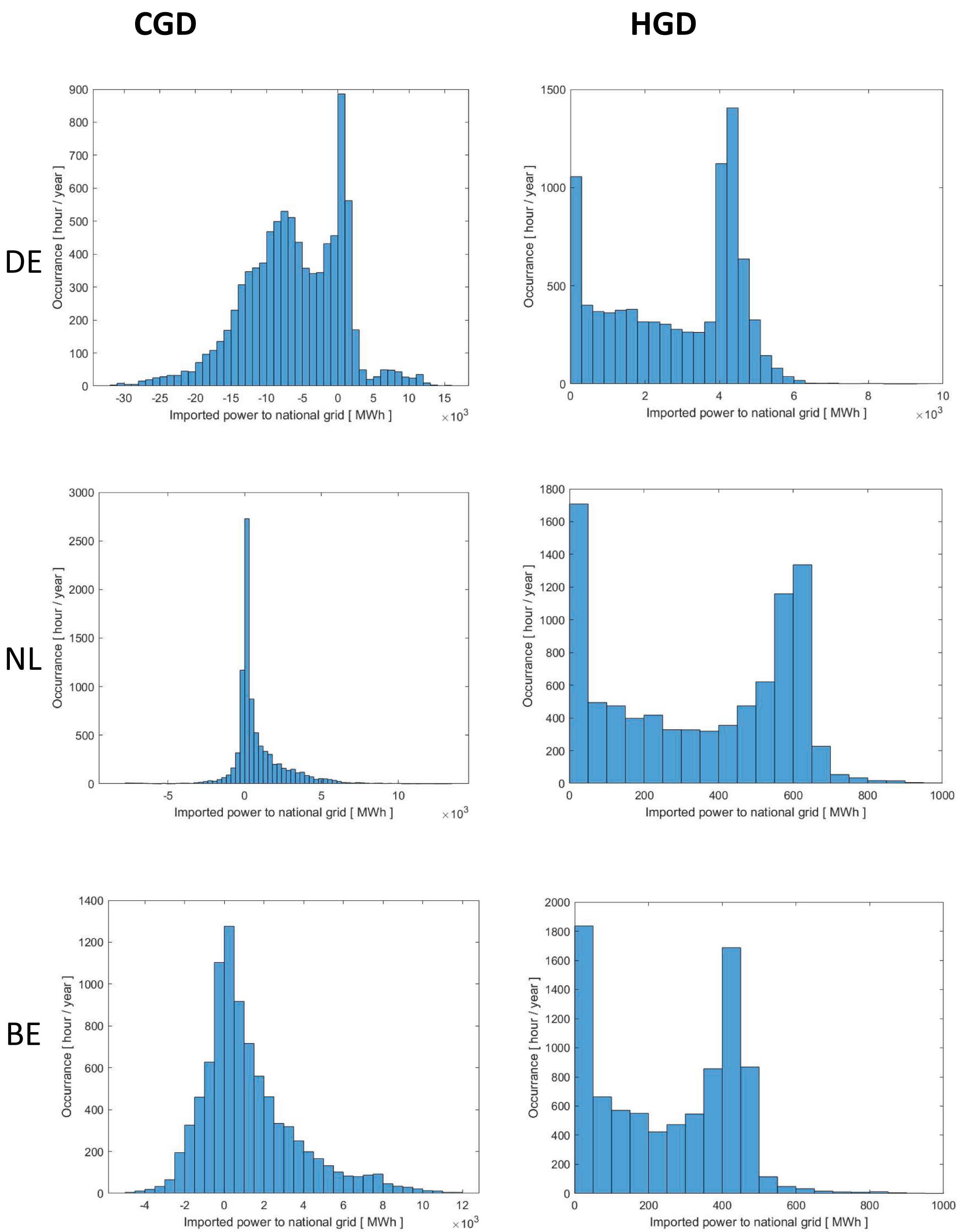

Fig. 8. (*continued*).

- According to [4], for a 100% renewable power system in Europe, the levelized cost of electricity drops from 69 [€/MWh] to 56 [€/MWh] is expected which correlates to a −19% price reduction. In our case, since the generation share of renewables between countries are different, one country experiences a more severe price response than the other. For example, Germany and the UK were shown to be one of the most profitable links while on average UK experiences −27% price drop and Germany experiences only +11% price increase. This is caused due to different characteristic lines defined per country with coefficient a.

The histogram of energy flows between the hub and the countries are given in Fig. 8. For each country, the graphs on the left side show optimized interconnection in terms of exported energy from their national grid (which flows through the hub) to the receiver country i.e. CGD. The graphs on the right side, however, represent optimized country generation distribution (CGD) in terms of imported wind energy from the hub (into their national grid). Negative export implies import and vice-versa.

Initially, there was no limit for energy flowing between countries as we were aiming at the highest value generation for both objectives. Using Fig. 8 we can optimise cable size to cover almost all the traffic. For instance, for CGD in the case of GB, power imports of up to 30 [GWh] can be seen, however, by increasing the infrastructure from 20 to 30 [GW], the extra power trades made possible are negligible. On the other hand, in the case of CGD for NO, an infrastructure of 5 [GW] could cover most of the traffic, yet this country has a considerable amount of hydropower storage which caused choosing to double the cable size. However, a limit on cable size affects the value generated from energy flow. Thus, there is a trade-off between the value generated and the infrastructure size. If the cable sizes are designed for extreme cases, then the value generated for each objective is not affected (this was our assumption in value generation calculations). Since infrastructure costs are high, and in order to have cable size for each objective, it is wise to choose a value that can cover most cases, to avoid impacting the generated value. Table 8 shows optimum cable sizes between each country and the hub.

The cable size required for CGD is much larger than for HGD. This is due to maximum wind power generation at the hub (which we set at 10 [GW]). We must also allow for the fact that power losses are larger for CGD because energy must first be delivered to the hub and then flow to a receiver country. Considering that most of the profit is generated from HGD, the most cost-effective solution is to design the hub for optimum HGD and use the infrastructure for CGD when there is less wind. By doing so, the designed infrastructure can always be fully used as well as lowering the hub's construction costs [18].

6. Conclusion

The effects of a proposed offshore wind park in the Dogger Bank area of the North Sea on the electricity market of countries surrounding the North Sea has been researched. Two objectives for the hub were defined; interconnection and generation distribution. First, interconnection is modelled and then the resulting market status is used as input for hub generation distribution. A linear regression analysis on the historic market data for each country was performed to simulate the supply price for higher or lower self-supplied power. The interconnection model aimed to find the most profitable combination of mutually exclusive links between NSCs. The hub generation distribution model aimed to find the most profitable destination for the generated wind power at the hub. Using the historic market and weather data for 2016, the following results were found.

- The results suggest by interconnecting the comparably sized electricity markets where one has a higher renewable electricity share, such as the UK and DE or DK and BE, the most price stabilization and profit is generated.
- For country generation distribution (CGD) using the hub merely as an interconnection point, for an average power flow is 82.1 [GW] an average value of 0.275 [M€/hour] is generated.
- For hub generation and distribution from a 10 [GW] capacity wind park at the hub which on average generates 6.3 [GW] wind power, the average value generation is 0.573 [M€/hour].
- Optimum cable capacities for the spokes were calculated for both scenarios; CGD and HGD.
- For country generation distribution, on average UK experiences the most severe price drop of −27% and Germany the most sever price increase of +11%. For HGD, electricity prices on average reduce by −4% to −6%.

Table 8
Optimum cable size for country generation distribution (CGD) and hub generation distribution (HGD) objectives.

Country	GB	NO	DK	DE	NL	BE
Optimum cable size for CGD [GW]	20	10	2	28	4	8
Optimum cable size for HGD [GW]	2	3	1	5	1	1

There were several assumptions in our model which can be used for future research:

- This interconnection model was restricted to find mutually exclusive links at any hour. Scenarios of 1 country supplying to n countries were not considered. The hub could be modelled as an independent "actor" by which all countries sell or receive to the hub at a certain hour so that the whole system reaches price equilibrium. A more advanced optimization method could define a global electricity price (which would be a function of all electricity prices) and aim to minimize that global price for CGD and HGD.
- A follow-up study can look at situations where cable capacity is limited or where the countries or the hub can store electricity for trade or consumption at a later moment. This particularly in the case of Norway with large hydro storage capacity can bring new insight.
- The price modelling system can be enhanced to include more time resolution and spatial location within zones of a country.
- Linear models for price estimation were used to calculate changes in electricity supply price. A non-linear estimation model, particularly near the generational limits, can discover a new power trade dynamic.
- This research assumes that there are no limits to power injection capacity. The main aim of this research was the highest price stabilization. This can be addressed in the model by restricting cable sizes.
- The transfer losses were not modelled in this research. A follow-up study can investigate various transfer approaches with different transmission loss modelling.

CRediT authorship contribution statement

Soheil Alavirad: Conceptualization, Methodology, Formal analysis, Investigation, Resources, Data Curation, Writing - original draft, Visualization. **Saleh Mohammadi:** Conceptualization, Methodology, Formal analysis, Resources, Writing, Supervision, Project administration, Writing - review & editing. **Michael Golombok:** Conceptualization, Methodology, Formal analysis, Resources, Writing, Supervision, Project administration, Writing - review & editing. **Koen Haans:** Writing - review & editing, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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